



July 31, 2002

Mary Cottrell  
Secretary  
Department of Telecommunications and Energy  
One South Station, 2<sup>nd</sup> Floor  
Boston, MA 02110

Dear Ms. Cottrell,

We are submitting this letter in response to D.T.E. 02-38, "Investigation by the Department of Telecommunications and Energy on its own motion into Distributed Generation". We applaud the Department's effort to better understand the issues associated with DG – and particularly as they affect the distribution companies. It is this interface that will ultimately determine the success of DG in Massachusetts.

GTI is pleased to have this opportunity to assist in this investigation. GTI is heavily engaged in the Distributed Energy industry and sees a growing need for DG and combined heat and power (CHP) in the electric energy marketplace. In support of this need GTI is leading numerous national and regional efforts to deploy various clean distributed energy technologies, and has spoken at over 40 industry forums on this subject. GTI's team provides a unique combination of technical and energy planning expertise that is unparalleled in the industry today and appears to be tailor-made to support the Department's investigation.

GTI is an independent, not-for-profit technology organization offering research and technical services, R&D program management, technology commercialization, and education and training. GTI was formed in 2000 by the combination of the Institute of Gas Technology (IGT), with its rich 60-year history in performing R&D and training for the gas industry, and the Gas Research Institute (GRI), with its 22-year history of program management.

GTI's Distributed Energy Center is at the forefront of integrated energy planning and clean energy technology deployment. Our Innovative Energy Conversion Technology Center is a leading developer of fuel cell technologies. Combined, both Centers represent over 60 of the industry's leading technologists, economists, engineers and planners experienced in the development and deployment of distributed energy systems.

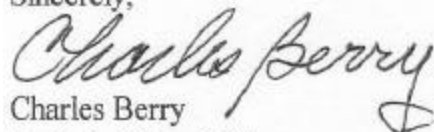
Both GTI's Distributed Energy Center and the Innovative Energy Conversion Technologies Center have performed numerous Distributed Energy projects, as that is the nature of both Centers. Some examples include:

- Energizing America's Cities: Development of futuristic plan for sustainable urban energy design for the International Sustainable Design Competition.
- The Chicago Industrial Energy Plan (similar plans being started in Philadelphia and New York)
- Development of Chicago's Energy Plan CHP and Distributed Energy Implementation Program
- The Midwest CHP Initiative and the Midwest CHP Application Center (and leading similar startup efforts in the Northeast, Southeast, and Northwest)
- GTI's DG Mutual Fund Fuel Cell Installations

GTI is also a member of the Northeast CHP Initiative (NECHPI) - a volunteer group organized by - but independent of - the U.S. Department of Energy, as a direct result of their Federal-level efforts to accelerate the adoption of CHP in the U.S. Its mission is to *"Lead the region in encouraging the use and implementation of CHP technologies; to drive CHP roadmap action items for the Northeast Region in Support of DOE's and EPA's goal of doubling the various stakeholder organizations in the region, including federal agencies, state agencies, utilities, project developers, equipment manufacturers, CHP users, universities, research institutions and public interest groups"*.

We hope that our perspective of the industry will prove valuable to you as the Department works to develop an understanding of the barriers that DG is facing in Massachusetts. DG can be a compelling 'win-win' – for the State, the distribution companies, and the electric energy consumer. GTI looks forward to providing any further assistance that might be needed to make it happen.

Sincerely,



Charles Berry  
Technical Specialist  
Gas Technology Institute

**Subject: D.T.E. 02-38 – Investigation by the Department of Telecommunications and Energy on its own motion into Distributed Generation**

GTI, DOE, EPA, and Massachusetts have a common interest in providing clean, stable, and affordable energy. Overall, GTI asserts that State policy that integrates Combined Heat and Power (CHP) and Distributed Generation (DG) into the electricity T&D infrastructure will benefit consumers in the following ways:

- ?? Increasing generation and supply at or near the customers, in effect providing for storage of electricity that will reduce market power and electricity price volatility.
- ?? Encouraging economic development by providing existing and new businesses with lower cost choices for electricity. CHP can supply electricity at 6 to 13 cents/kWH.
- ?? Reducing grid costs by increasing grid utilization. In some regions, nearly 50% of the cost of T&D is incurred to supply the last 10% of demand. A recent study conducted by NYSERDA indicates that over 75% of the DG potential in NY is for commercial and institutional facilities (Nexus Report) with on-peak energy demand only. This indicates that DG will increase grid utilization and lower costs.
- ?? Improving electricity reliability by generating power near or at the customer's site.

Consequently, GTI welcomes the opportunity to offer comments on the Department's following questions:

1. Refer to current distribution company interconnection standards and procedures in Massachusetts. Do these standards and procedures act as a barrier to the installation of distributed generation? If so, please describe.
  - a. If the current standards and procedures act as barriers to the installation of distributed generation, please describe what steps the Department should take to remove these barriers. As part of this response, please discuss whether the Department should establish uniform technical interconnection standards and procedures for distributed generation.

The recent outcry for uniform and streamlined interconnection standards was primarily prompted by the emergence of new small-scale environment-friendly DG technologies like microturbines and fuel cells. Current technical interconnection requirements for distributed generation may differ from utility to utility and state to state. Customers attempting to install these technologies may also be required to pay for pre-interconnection engineering studies which can add significant cost to the project. The typical lack of a single utility point of contact or a defined process for distributed generation interconnection matters, and the absence of simple standardized applications and agreements serves to delay and discourage customer-owned DG projects. With standards and/or testing protocols varying arbitrarily from utility to utility, project costs have increased due to technical, institutional and business practices imposed by utilities. The economics of projects involving such small-scale systems typically cannot tolerate high interconnection costs. (Additional information is provided in the U.S. Department of Energy's report "Making Connections" which can be found at <http://www.nrel.gov/docs/fy00osti/28053.pdf>. Additional resources on interconnection issues can be found on USDoE's website <http://www.eren.doe.gov/distributedpower/library.html>)

In addition, some manufacturers are incorporating built-in relay protection in an effort to improve project economics by eliminating the need for expensive add-on equipment. Unfortunately, due to the lack of type testing protocols, and standards that vary arbitrarily from utility to utility, and the reluctance of some utilities to accept this protection, some DG equipment manufacturers are reluctant to design embedded protection. Uniform standards can help eliminate this problem.

The development of IEEE P1547 was initiated in March of 1999 to address this need. Unfortunately, the Writing Committee is now on Draft 09 and the Balloting Committee is still trying to garner consensus. One of the reasons the IEEE effort is taking so long is the fact that the Standards Committee has elected to write a “one size fits all” standard for DG systems from 1 kW to 10 MW connected to any and all kinds of distribution systems. Even if the next ballot is successful, the IEEE is planning several more projects to complete the overall effort. The IEEE Standards Board has approved the following projects:

?? *P1589 Draft Standard for Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.*

?? *P1608 Draft Application Guide for IEEE Standard 1547 – Standard for Interconnecting Distributed Resources with Electric Power Systems.*

These efforts are expected to take 1-2 years. In addition, a new Project Authorization Request has recently been approved - *Guidelines for the Monitoring, Information Exchange and Control for Distributed Resources*. This effort is expected to take 2-2½ years.

The delays associated with the development of a consensus interconnection standard are not helping today’s emerging DG technologies. Additional action is needed to open these markets *now*, such as the rulemaking and guidance that has been taken by public utility commissions in the States of Texas, California, New York and Wisconsin. In some instances, these states have referenced draft versions of IEEE 1547 to provide the technical basis for their standard.

- b. Please comment on whether the Department should adopt the IEEE's uniform technical interconnection standards, or the uniform standards adopted by other states, for use in Massachusetts.

Massachusetts would do well to tackle a smaller piece of the puzzle as did New York (see <http://www.dps.state.ny.us/distgen.htm>). Since most of these newer, environment-friendly DG technologies are of relatively small scale, they are less likely to cause some of the more serious problems the distribution companies are trying to prevent (i.e. islanding, reverse current flow, grid instability, flicker, harmonic distortion, safety hazards, etc.). Consequently, interconnection requirements for this class of DG can be much simpler and more straightforward than what would be required for DG of the MW-class. In the interest of expediting the implementation of DG, Massachusetts could develop standard interconnection requirements for small-scale technologies in a relatively short time frame. Very simple interconnection standards have been developed for net-metered Photovoltaic systems 10 kVA or less. Standards for DG systems 300 kVA or less *that incorporate reverse power protection* could also be very simple. *Type Testing Protocols* have already been developed for this class of equipment that has built-in relay protection. *Type Testing Protocols* still need to be developed for today’s state-of-the-art reverse power controls. Pre-certified and approved equipment can avoid the delays that are associated with the *field verification* of protection packages. These are the kind of standards that need to be put in place in the near-term. Meanwhile, a parallel effort can get underway to develop the somewhat more detailed standards that are required for the MW-class of DG, such as what has been done in Texas and Wisconsin. Massachusetts could consider referencing existing drafts of IEEE 1547 now, and then perhaps adopt the final version and other supplemental guides and standards as they become available.

To summarize, significant work has already been done to identify the barriers facing DG. Recurrently, interconnection obstacles are identified as the number one problem. Consequently, in the interest of furthering the development of DG and new clean technologies, it is strongly recommended that Massachusetts establish uniform technical interconnection standards and procedures for distributed generation. Without them, the promises of clean DER technologies such as fuel cells, microturbines, advanced turbines, and advanced reciprocating engines may not be realized.

Concurrently, an effort could get underway to review the parallel generation agreements used by the various IOUs in Massachusetts. Simplifying these documents would help streamline the overall interconnection

process.

2. Refer to current distribution company standby service tariffs. Do these tariffs act as a barrier to the installation of distributed generation? If so, please describe.

High stand-by and back-up charges can ruin the economics of self-generation. If high standby charges don't outright kill a DG project, they could cause a potential DG project to meet all of its needs through 'grid-isolated' self-generation, thereby negating any benefits the project might provide by operating in parallel with the grid. Standby and back-up charges must be reasonable. The value put on 'stranded assets' should be offset by the value of avoided T&D reinforcement. IOUs have traditionally been allowed to recover these costs by adding a competitive transition charge (CTC) to the retail bill. Like the delivery charge, the CTC should only be applied to the peak contribution of standby users as a group, based on the diversified standby demand component added simultaneously to the system peak demand. The ability of utilities to recover capital expenditures should be a function of performance and not just throughput. An effort should be initiated to investigate tariff reform and other regulatory and institutional policies that are hindering the deployment of DG systems in Massachusetts.

- a. Please discuss the appropriate method for the calculation of standby or back-up rates associated with the installation of distributed generation. As part of this response, please discuss whether other states have established policies regarding back-up rates associated with distributed generation that may be appropriate for adoption in Massachusetts.

Fair standby charges should be assessed at a rate - and under terms that are just and reasonable - when taking into account the actual incremental cost to the distribution utility for providing this service. The Department should consider reducing the portion of the T&D cost that is attributed to the "contract demand charge". NYSERDA's recent research indicates that DG will slow electric demand - not decrease utility grid sales. Therefore, the utility is expected to increase revenues even with increased utilization of DG. Furthermore, the electric grid will benefit from the installation of distributed generators that can be considered 'storage' while reducing peak loads and price volatility. New England and California both learned that even with the deregulation of generation, there were only a few large suppliers who were able to exert market power. Both, New England and California suffered high electricity price volatility due in part to a lack of storage capacity (lack of DG).

Some 'lessons learned' might also be taken from the NY Public Service Commission's investigation into Niagara Mohawk's Rule 12. On March 12, 2002, the Niagara Mohawk Power Corporation ("NIMO") filed with the New York Public Service Commission ("Commission") a Joint Proposal setting forth on behalf of the signatories a partial resolution and settlement of issues related to NIMO's electric standby rates. The standby rates established in the Joint Proposal, if adopted, will be inconsistent with the Commission's recently adopted guidelines for standby rate design and will dramatically set back efforts to introduce distributed generation in New York State. The Niagara Mohawk filing is similar to many other states where the majority of the T&D costs are allocated as local with virtually none of the costing being classified as *shared*. Niagara Mohawk argued that 70-80% of the T&D costs were *local*, resulting in high standby charges. However, under the NIMO 1994 ECOS, the company's latest approved cost of service study, the following percentages of plant are allocated on demand to *primary* within the distribution plant accounts 364-367:

364	Poles	47.56%
365	OH Conductors	52.2%
366	UG Conduit	78.2%
367	UG Conductors	75.6%

Overall, the 1994 ECOS allocates 41% of distribution plant on demand to primary. Factoring in operation and maintenance (O&M) and administrative and general (A&G), results in roughly \$52 million of the \$113 million of total delivery costs attributable to primary. Furthermore, if one takes into consideration the percentage of local facilities already embedded in the customer charge, following the 1994 ECOS would result in a further allocation of primary distribution plant to shared. Consistent with the above, at least 50% of NIMO's primary distribution system plant should be allocated as "shared".

In addition the NIMO filing suggests that the distribution company must maintain reserve power equal to the total of *all* DG systems on the distribution system. This results in large standby charges for DG sites that in most cases make DG uneconomical, thereby, providing the distribution company with a monopoly. Standby tariffs should account for the random nature of the load that DG outages place on the system and the diversity of such occurrences. There is a strong incentive to run on-site generation at peak times since this is precisely the time when the value of the power is greatest. On a probabilistic basis, there is *some* likelihood that DG units might be down at the system peak. Likewise, on a probabilistic basis, there is *little* likelihood that *most* of the DG units will be down at the time of a system peak.

The Department should also consider and investigate how much of the existing T&D system has already been paid for by consumers. If the majority of the distribution system has already been amortized, assessing customers a standby charge for existing assets may be inappropriate.

The Department should also consider *Reserve Margin Impact* on standby charges. PURPA provides special guidelines for utility rates applicable to customer-owned generation meeting PURPA guidelines. Under PURPA, special rates are required for backup power, maintenance power and interruptible power. PURPA specifically states that rates for the sale of back-up power or maintenance power to eligible facilities:

- (1) “shall not be based on an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility’s system will occur simultaneously or during the system peak, or both; and
- (2) shall take into account the extent to which schedule outages of the qualifying facilities can be usefully coordinated with schedule outage of the utility’s facilities.”

What PURPA states is that the rate design must assume diversity with respect to simultaneous peaks unless data shows otherwise. By assuming that generator outages during peak periods occur simultaneously and that factual data does not exist, directly contravenes PURPA.

Electric utility organizations within the U.S. operate under NERC guidelines with respect to reserve capacity margins necessary to maintain reliable electric service. Under these guidelines, utilities typically maintain generation reserve in the range of 12-18% of the total coincidental peak demand of customers to which the utility provides firm electric service. In deregulated states in which utilities have divested themselves of generation, the suppliers are required to maintain the reserves as a requirement for delivering firm power.

Under this same approach, a utility supplying standby service to 20 customers each owning a 1 MW generator would not have to supply 20 MW of standby generation. Rather, the amount of standby capacity required would be the aggregated maximum diversified standby demand of on-site generators during a peak hour while maintaining a given threshold of risk. Since customer-owned generators are typically small compared to utility-owned (or controlled) generators, the required reserve capacity margin would be only in the range of 10% or less.

3. Please discuss the role of distributed generation with respect to the provision of reliable, least-cost distribution service by the Massachusetts distribution companies.

Existing business practice and business models often reflect the old regulated electricity industry dominated by vertically integrated utilities and central station power plants. New business models are needed to capture the value of non-utility owned distributed power in delaying or avoiding transmission and distribution system upgrades, the use of distributed power for ancillary services and for improving system reliability, power quality and reducing line losses. New competitive business models need to be developed that will permit the realization of the full economic value of distributed power in competitive markets.

Current utility tariffs and rate design as a rule do not price distribution services to account for system benefits that could be provided by distributed generation. Well-sited DG can provide various system benefits including the deferral of capital projects designed to reinforce the current system, deferral of expansion projects to serve new demand, and reduced replacement costs for distribution infrastructure that fails as a result of overload. More

appropriately designed tariffs can provide for standby and backup power services without incurring prohibitive charges.

- a. What steps should the distribution companies take in order to identify areas where the installation of distribution generation would be a lower-cost alternative to system upgrades and additions?

The distribution companies should start by identifying the highest cost reinforcement projects. DG alternatives should then be identified and economic comparisons performed.

- b. What steps should the distribution companies take to encourage the installation of cost-effective distributed generation in their service territories?

Local distribution costs are typically not visible, either because of current tariff structures or a lack of public disclosure. In the absence of this information the potential DG project cannot assess the value it might provide to the distribution company at *site-specific* locations. Distribution companies should first divulge the location of distribution constraints. The Department should then work with the distribution companies to develop incentive programs that would encourage the installation of DG in those areas. The distribution companies could also agree to waive the fees that they would normally charge a customer who is interconnecting DG equipment with the grid in those areas. The distribution companies could also agree to expedite the processing of interconnection applications for those customers, a la California's Rule 21 "Fast Track Review Process" (see attached newsletter for a summary of California's Rule 21).

4. What other issues are appropriate for consideration as part of the Department's investigation of distributed generation?

Some policy makers have been lead to believe that DG will hurt consumers by increasing T&D costs due to lost revenue/load. GTI's research indicates that quite the opposite may be true. Our research shows that an aggressive DG program can 'at best' only slow the growth of electricity consumption - not reduce distribution company revenue.

Much of the current DG debate fails to recognize that deregulation to date has only impacted the wholesale market. The impact of deregulation started 10 years before generators were competing (e.g during the late 80's). *The threat of competition* forced utility electric generation plant management to lower costs substantially. Baseload power plant operators believed that they would not be operating in the year 2000 unless they improved operating performance to match the least expensive operators (\$0.01/kWh).

Baseload electric generators met this challenge by spending billions of consumer dollars to upgrade generating plant equipment and improving practices to decrease operating costs. Generators exceeded expectations with capacity factors rising to almost 90%, repowering to increase output, and significantly lowering operating costs. Wholesale competition also spurred investment in Combined-cycle Combustion Turbines in TX, CA, and the NorhtEast where these 50+% efficiency machines would displace more costly simple-cycle gas and oil-fired power plants. What Massachusetts can learn from generation deregulation is that the threat of competition is a powerful tool. Second is that competition requires a competitor. In the case of generation, the best operating plants in the country set the standard that others would have to meet to stay in business. The threat of shutdown was a powerful motivator. Who will be the competitor for T&D?

T&D costs in many regions - for both residential and commercial customer classes - are the largest contributor to the cost of electricity. In the wake of wholesale deregulation, how can Massachusetts achieve operating efficiency improvements in T&D? Grid utilization and competition may be the answer. DG can

help with both. DG can be utilized to reduce on-peak demand while providing competition. Distribution companies could be encouraged to utilize DG to improve the distribution system. Regulators could provide incentives (e.g. increased ROI) for improvement. Several possible strategic policy initiatives include:

- ?? Establish Grid Utilization Targets (e.g. ratio of peak to baseload) – Regulators could establish targets or goals for distribution companies. These targets would vary based on regional climate differences that impact grid utilization. For example, grid utilization is higher in Texas vs. Chicago due to weather.
- ?? Establish DG as the Benchmark for Delivered Cost – DG could be used to set the standard by establishing a competitive delivery price.
- ?? Allow T&D companies to own and operate DG systems below 20MW – Currently T&D companies own, operate, and maintain the transformers located at the customers site. It is not a stretch for them to own DG. This would allow distribution companies to invest in innovative DG applications that improve grid utilization, increase energy efficiency, add generation at or near the customer, and increase customer energy reliability.
- ?? Modify rate tariff structures to encourage “On-Peak” Distributed Energy
  - ✍✍ Appropriately allocate “On-Peak” distribution costs via demand charges
  - ✍✍ Optimize standby rates
  - ✍✍ Streamline interconnect studies and fees – consider waiving fees for projects in constrained areas
  - ✍✍ Eliminate optional rates aimed at reducing consumer choice
  - ✍✍ Allow municipalities and cities to offset electric bills with renewable and CHP electricity supply produced at remote sites (successfully applied in Michigan)
- ?? Consider including an *interruptible* option where customers are not guaranteed service on demand. Only if excess system capability is available will the customer receive service. In effect, this would exempt the utility from having to build infrastructure or enter into contracts to ensure sufficient power for this customer. As such the “contract demand charge” could be waived.
- ?? Consider Sitting, Permitting and Environmental Regulation Reform – Zoning, air permits, water use permits, comprehensive environmental plan approval, and other regulatory processes can both delay and increase the costs of distributed generation projects. These issues typically relate to site-specific concerns. In general, distributed power technologies are not covered in national building, electrical, and safety codes. The codes do address photovoltaics; but this was the result of many years of effort by the Department of Energy, its national laboratories, standards organizations and industry. Local code and zoning officials are typically not familiar with many new distributed generation technologies. Environmental regulations are not currently administered in a way which gives credit for the overall pollution reduction effects of high efficiency distributed power technologies such as combined heat and power systems.
- ?? Include DG in Electric Supply Integrated Resource Planning– Establish goals that provide for using DG to meet a portion of any new supply requirements. Under this scenario, Massachusetts consumers receive the benefits of private investment into new supply. The Department could also consider a *contract demand charge* as a means for providing the distribution company and its generation suppliers with a defacto monopoly by discouraging private investment in supply.
- ?? Consider pilot programs to test the effectiveness of DG for addressing T&D constraints. New York has implemented such a program (see <http://www.dps.state.ny.us/fileroom/doc10644.pdf>).
- ?? A GIS study should be conducted to identify load pockets and the location of distribution constraints. The study could also locate customers with good thermal loads and/or premium power needs, since these customers would typically realize the greatest benefit from self-generation.
- ?? Location-based marginal pricing or zonal pricing could also impact the viability of DG for addressing distribution constraints. If electric tariffs can be designed to make only the customers who are causing the T&D constraints bear the cost of T&D reinforcement and any new construction that is required to serve them, it is likely that these increased energy costs will improve the economic viability of customer-owned DG. (The New England ISO intends to initiate “locational” pricing on Jan 1, 2003.)

